LISTING OF THE CLAIMS

This listing of claims will replace all prior versions, and listings, of claims in the application:

Claims:

1. (Currently Amended) A method of detecting a fracture with residual width from a previous well treatment during a well fracturing operation in a subterranean formation containing a reservoir fluid, comprising the steps of:

(a) injecting an injection fluid into the formation at an injection pressure exceeding the formation fracture pressure;

(b) gathering pressure measurement data from the formation during the injection and a subsequent shut-in period;

(c) transforming the pressure measurement data into a constant rate equivalent pressure; and

(d) detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data, said dual unit-slope being indicative of the presence of a fracture retaining residual width;

wherein

the reservoir fluid is compressible;

the transformation of pressure measurement data is based on the properties of the compressible fluid contained in the reservoir; and

the transforming step comprises the step of calculating:

- a shut-in time relative to the end of the injection: $\Delta t = t - t_{ne}$;

- an adjusted time: $t_a = (\overline{\mu c_t}) \int_0^{\Delta t} \frac{d\Delta t}{(\mu c_t)_w}$; and

- an adjusted pseudo pressure difference: $\Delta p_a(t) = p_{aw}(t) - p_{ai}$

where $p_a = \frac{\overline{\mu}_g \overline{z}}{\overline{p}} \int_0^p \frac{pdp}{\mu_g z}$;

wherein:

t_{ne} is the time at the end of injection;

$\bar{\mu}$ is the viscosity of the reservoir fluid at average reservoir pressure;

$(\mu c_t)_w$ is the viscosity compressibility product of wellbore fluid at time t;

$(\mu c_t)_0$ is the viscosity compressibility product of wellbore fluid at time $t = t_{ne}$;

p is the pressure;

$\bar{p}$ is the average reservoir pressure;

$p_{aw}(t)$ is the adjusted pressure at time t;

p_{at} is the adjusted pressure at time $t = t_{ne}$;

c_t is the total compressibility;

$\bar{c}_t$ is the total compressibility at average reservoir pressure; and

z is the real gas deviator factor.

2. (Original) The method of claim 1 wherein the time of injection is limited to the time required for the reservoir fluid to exhibit pseudoradial flow.

3. (Canceled)

4. (Canceled)

5. (Currently Amended) The method of claim [[4]] 1 further comprising the step of plotting a log-log graph of a pressure function versus time: $I(\Delta p_a) = F(t_a)$;

where $I(\Delta p_a) = \int_0^{t_a} \Delta p_a dt_a$.

6. (Currently Amended) The method of claim [[4]] 1 further comprising the step of plotting a log-log graph of a pressure derivative function versus time: $\Delta p_a' = f(t_a)$;

where $\Delta p_a' = \dfrac{d(\Delta p_a)}{d(\ln t_a)} = \Delta p_a t_a$.

7. (Currently Amended) The method of claim [[3]] 1 wherein the injection fluid is slightly compressible and contains desirable additives for compatibility with said formation.

8. (Currently Amended) The method of claim [[3]] 1 wherein the injection fluid is compressible and contains desirable additives for compatibility with said formation.

9. (Original) The method of claim 1 wherein

the reservoir fluid is slightly compressible; and

the transformation of pressure measurement data is based on the properties of the slightly compressible fluid contained in the reservoir.

10. (Currently Amended) The method of claim 9 wherein the transforming step comprises the step of calculating:

~~- a shut-in time relative to the end of the injection:~~ $\cancel{\Delta t = t - t_{ne}}$ ~~; and~~

- a pressure difference: $\Delta p(t) = p_w(t) - p_i$;

wherein:

$\cancel{t_{ne}}$ ~~is the time at the end of injection;~~

$p_w(t)$ is the pressure at time t; and

p_i is the initial pressure at time $t = t_{ne}$.

11. (Previously Presented) The method of claim 10 further comprising the step of plotting a log-log graph of a pressure function, $I(\Delta p)$, versus time, Δt

where $I(\Delta P) = \int_0^{\Delta t} (\Delta p)(d\Delta t)$.

12. (Original) The method of claim 10 further comprising the step of plotting a log-log graph of a pressure derivatives function versus time: $\Delta p' = f(\Delta t)$;

where $\Delta p' = \dfrac{d(\Delta p)}{d(\ln \Delta t)} = \Delta p \Delta t$.

13. (Original) The method of claim 9 wherein the injection fluid is compressible and contains desirable additives for compatibility with said formation.

14. (Original) The method of claim 9 wherein the injection fluid is slightly compressible and contains desirable additives for compatibility with said formation.

15. (Currently Amended) A system for detecting a fracture with residual width from a previous well treatment during a well fracturing operation in a subterranean formation containing a reservoir fluid, comprising:

- a pump for injecting an injection fluid at an injection pressure exceeding the formation fracture pressure;

- means for gathering pressure measurement data in the wellbore at various points in time during the injection and a subsequent shut-in period;

- processing means for transforming said pressure measurement data into a constant rate equivalent pressure; and

- means for detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data, said dual unit-slope being indicative of the presence of a fracture retaining residual width;

wherein

the reservoir fluid is compressible;

the transformation of pressure measurement data is based on the properties of the compressible reservoir fluid; and

the transformed data are obtained by calculating:

- a shut-in time relative to the end of the injection: $\Delta t = t - t_{ne}$;

- an adjusted time: $t_a = (\overline{\mu c_t}) \int_0^{\Delta t} \frac{d\Delta t}{(\mu c_t)_w}$; and

- an adjusted pseudo pressure difference: $\Delta p_a(t) = p_{aw}(t) - p_{ai}$

where $p_a = \frac{\overline{\mu}_g \overline{z}}{\overline{p}} \int_0^p \frac{p\,dp}{\mu_g z}$;

wherein:

t_{ne} is the time at the end of injection;

$\overline{\mu}$ is the viscosity of the reservoir fluid at average reservoir pressure;

$(\mu c_t)_w$ is the viscosity compressibility product of wellbore fluid at time t;

$(\mu c_t)_0$ is the viscosity compressibility product of wellbore fluid at time $t = t_{ne}$;

p is the pressure;

$\overline{p}$ is the average reservoir pressure;

$p_{aw}(t)$ is the pressure at time t;

p_{at} is the pressure at time $t = t_{ne}$;

c_t is the total compressibility;

$\bar{c}_t$ is the total compressibility at average reservoir pressure; and

z is the real gas deviator factor.

16. (Original) The system of claim 15 wherein the processing means comprises graphics means for plotting said transformed pressure measurement data.

17. (Original) The system of claim 15 wherein the time of injection of said injecting means is limited to the time required for the reservoir fluid to exhibit pseudoradial flow.

18. (Canceled)

19. (Canceled)

20. (Currently Amended) The system of claim [[19]] 15 further comprising graphic means for plotting a log-log graph of a pressure function versus time: $I(\Delta p_a) = f(t_a)$;

where $I(\Delta p_a) = \int_0^{t_a} \Delta p_a dt_a$.

21. (Original) The system of claim 19 further comprising graphic means for plotting a log-log graph of a pressure derivative function versus time: $\Delta p_a' = f(t_a)$;

where $\Delta p_a' = \dfrac{d(\Delta p_a)}{d(\ln t_a)} = \Delta p_a t_a$.

22. (Original) The system of claim 15 wherein the injection fluid is compressible and contains desirable additives for compatibility with said formation.

23. (Original) The system of claim 15 wherein the injection fluid is slightly compressible and contains desirable additives for compatibility with said formation.

24. (Original) The system of claim 15 wherein:

the reservoir fluid is slightly compressible; and

the transformation of pressure measurement data is based on the properties of the slightly compressible reservoir fluid.

25. (Currently Amended) The system of claim 24 wherein the transformed data are obtained by further calculating:

~~a shut-in time relative to the end of the injection:~~ $\cancel{\Delta t = t - t_{ne}}$;

- a pressure difference: $\Delta p(t) = p_w(t) - p_i$;

wherein:

~~t_{ne} is the time at the end of injection;~~

$p_w(t)$ is the pressure at time t; and

p_i is the initial pressure at time $t = t_{ne}$.

26. (Previously Presented) The system of claim 25 further comprising graphic means for plotting a log-log graph of a pressure function, $I(\Delta p)$, versus time, Δt

where $I(\Delta P) = \int_0^{\Delta t} (\Delta p)(d\Delta t)$.

27. (Original) The system of claim 25 further comprising graphic means for plotting a log-log graph of a pressure derivatives function versus time: $\Delta p' = f(\Delta t)$;

where $\Delta p' = \dfrac{d(\Delta p)}{d(\ln \Delta t)} = \Delta p \Delta t$.

28. (Currently Amended) A system for detecting a fracture with residual width from previous well treatment during a well fracturing operation in a subterranean formation containing a reservoir fluid, comprising:

- a pump for injecting an injection fluid at an injection pressure exceeding the formation fracture pressure;

- means for gathering pressure measurement data in the wellbore at various points in time during the injection and a subsequent shut-in period;

- processing means for transforming said pressure measurement data into a constant rate equivalent pressure; and

- graphics means for plotting said transformed pressure measurement data representative of before and after closure periods of wellbore storage, and for detecting a dual unit-slope wellbore storage indicative of the presence of a fracture retaining residual width;

wherein

the reservoir fluid is compressible;

the transformation of pressure measurement data is based on the properties of the compressible reservoir fluid; and

the transformed data are obtained by calculating:

- a shut-in time relative to the end of the injection: $\Delta t = t - t_{ne}$;

- an adjusted time: $t_a = (\overline{\mu c_t}) \int_0^{\Delta t} \frac{d\Delta t}{(\mu c_t)_w}$; and

- an adjusted pseudo pressure difference: $\Delta p_a(t) = p_{aw}(t) - p_{ai}$

where $p_a = \frac{\bar{\mu}_g \bar{z}}{\bar{p}} \int_0^p \frac{pdp}{\mu_g z}$;

wherein:

t_{ne} is the time at the end of injection;

$\bar{\mu}$ is the viscosity of the reservoir fluid at average reservoir pressure;

$(\mu c_t)_w$ is the viscosity compressibility product of wellbore fluid at time t;

$(\mu c_t)_0$ is the viscosity compressibility product of wellbore fluid at time $t = t_{ne}$;

p is the pressure;

$\bar{p}$ is the average reservoir pressure;

$p_{aw}(t)$ is the pressure at time t;

p_{ai} is the pressure at time $t = t_{ne}$;

c_t is the total compressibility;

$\bar{c}_t$ is the total compressibility at average reservoir pressure; and

z is the real gas deviator factor.

29. (Currently Amended) The system of claim 28 wherein

~~- the reservoir fluid is compressible;~~

- the injection fluid is compressible or slightly compressible and contains desirable additives for compatibility with said formation~~; and~~

~~- the transformation of pressure measurement data is based on the properties of the compressible reservoir fluid~~.

30. (Original) The system of claim 28 wherein:

- the reservoir fluid is slightly compressible;

- the injection fluid is compressible or slightly compressible and contains desirable additives for compatibility with said formation; and

- the transformation of pressure measurement data is based on the properties of the slightly compressible reservoir fluid.